March 3, 2014

Via Electronic Mail
To: GSRuleGuidanceComments@epa.gov
Ann M. Codrington, Director
Drinking Water Protection Division
Office of Ground Water and Drinking Water
U.S. Environmental Protection Agency
1200 Pennsylvania Avenue, NW (MC-4607M)
Washington, DC 20460

Comments of the Clean Air Task Force on U.S. EPA's DRAFT Underground Injection Control (UIC) Program Guidance on Transitioning Class II Wells to Class VI Wells, Doc. No. EPA 816-P-13-004

Ms. Codrington:

Clean Air Task Force ("CATF") is pleased to have the opportunity to comment on U.S. EPA's "Geologic Sequestration of Carbon Dioxide: Draft Underground Injection Control ("UIC") Program Guidance on Transitioning Class II Wells to Class VI Wells" (Dec. 2013) (hereinafter the "draft Guidance"). Founded in 1996, CATF is a nonprofit organization dedicated to restoring clean air and healthy environments through scientific research, public education and legal advocacy.

We appreciate EPA's work on this issue, however we ultimately and reluctantly conclude after reviewing the draft Guidance, that EPA should withdraw it and reissue a new draft that is based on accurate understandings of incidental enhanced oil recovery ("EOR") carbon dioxide ("CO_2") storage, and on the extent to which a change in the primary purpose of injection does and does not result in increased risk to underground sources of drinking water ("USDWs"). The current draft Guidance falls far short of this goal.

Background

For the foreseeable future, fossil fuels will continue to play an integral role in energy generation, in the U.S. and abroad. And, also for the foreseeable future, carbon capture and storage – whether incidental to EOR operations or through sequestration in saline geologic formations – is highly likely to be the only technology proven and available for isolation from atmospheric release of the large amounts of CO_2 emitted from fossil-fueled energy production. While the UIC rules are necessarily designed to protect underground sources of drinking water, EPA has separately expressed regulatory policy interest in a regulatory pathway for monitoring geologic storage projects against releases of CO_2 to the atmosphere. *See* Standards of Performance for

Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 1,430, 1,482-84 (Jan. 8, 2014); *and* Mandatory Reporting of Greenhouse Gases: Injection and Geologic Sequestration of Carbon Dioxide, 75 Fed. Reg. 75,060 (Dec.1, 2010).

EPA has also correctly recognized elsewhere the value of incidental storage in EOR fields, noting that EPA "expect[s] that for the immediate future, virtually all of the CO_2 captured at EGUs will be injected underground for long-term geologic sequestration at sites where enhanced oil recovery is also occurring."[1] 79 Fed. Reg. at 1482. Enhanced oil recovery storage is an important bridge to fully built-out sequestration, because the subsurface in EOR fields is already understood, and oil-producing reservoirs also provide known injectivity and storage capacity. Injected CO_2 is known to be effectively contacting pore space in the reservoirs, as it displaces the recovered oil resource.[2] This effective, proven utilization of underground reservoir space supports the understanding that injected CO_2 will be contained by the same geologic traps and mechanisms that have contained hydrocarbons for millions of years.[3] In addition, ongoing EOR activity offers immediately available, existing injection facilities and pipelines and four decades of carbon management experience.[4] Finally, many oilfields are known to contain multiple saline reservoirs above or below the producing layers, that can also be utilized to hold captured anthropogenic CO_2 in so-called "stacked storage."[5]

For these reasons, EPA should consistently work to encourage, and not to inadvertently discourage, EOR owners and operators (hereinafter "operators") to use captured CO_2 in oilfields, through all of its regulatory and guidance actions.

---

[1] Indeed, carbon storage incidental to EOR activity has been occurring in the United States for the past 40 years, with more than 850 million metric tonnes injected. Hill, *et al*., *Geologic carbon storage through enhanced oil recovery,* 37 Energy Procedia 6,808, 6,811 (2013). While data on CO_2 retention is rarely found in the literature, since it generally involves assertedly confidential contractual information on CO_2 purchase volumes, net CO_2 retention and storage has been estimated based on the experience at several fields. Occidental Petroleum suggests, from the performance of its Denver Unit in the Permian Basin of West Texas, that only 0.3% of the total CO_2 injected was lost from fugitive and operating emissions, and therefore the remaining 99% + was stored. Hydrogen Energy California Power Plant Licensing Case, Docket Number: 08-AFC-8A (Amended Application For Certification) *available at*: http://www.energy.ca.gov/sitingcases/hydrogen_energy/ and http://www.energy.ca.gov/sitingcases/hydrogen_energy/documents/others/2012-06-20_OEHI_Project_Overview_workshop_presentation.pdf. In another analysis, the field life carbon balance at SACROC field in West Texas suggests that taking into account vented CO_2 and emissions of CO_2 associated with the CO_2 injections and EOR, 93% of the CO_2 was estimated to be stored. Charles E. Fox, Kinder Morgan CO_2 Company, "CO_2 EOR Carbon Balance" (2013) *available at*: http://www.co2conference.net/wp-content/uploads/2013/05/Fox-KM-Presentation-SACROC.pdf

[2] Hill, *et al*., 37 Energy Procedia at 6,810.

[3] *Id.* at 6,810 -11.

[4] *Id.* at 6,811.

[5] *Id.* at 6,811-12.

To that end, the reissued Guidance should be based on accurate understandings of incidental EOR storage, and of the extent to which a change in the primary purpose of injection does and does not result in increased risk to USDWs. It should also describe a clear and reasonable transition process from Class II to Class VI permitting, as needed, recognizing the shared authority between Class II and Class VI Directors, as described in the following section of these comments.

It is our hope to provide EPA with suggestions to improve the Guidance so it does not discourage the use of anthropogenic CO_2 and the transition to Class VI permitting. EPA's reissued Guidance can and should be helpful to operators, to the Class II Directors that retain authority over enhanced oil recovery facilities, and to the Class VI Directors who must work with them to ensure a smooth transition where one is warranted.

EPA's Guidance Must Recognize the Shared Jurisdiction Between the Class II and Class VI Directors, During the Transition Process.

As an initial matter, it is important for the reissued Guidance to correctly describe the relationship between the Class II and Class VI Directors, with respect to EOR storage activity and through the transition to Class VI permitting.

The UIC General Provisions define "Director" as "the Regional Administrator, the State director, or the Tribal director as the context requires, or an authorized representative. Where there is no approved State or Tribal program, and there is an EPA administered program, "Director" means the Regional Administrator…." 40 C.F.R. § 146.3. Currently all states have primacy over EOR Class II well permitting, but no state has primacy over Class VI permitting.[6] That means that during the transition period described by EPA's Guidance, the State Director has authority over EOR activity, and the relevant EPA Regional Administrator has authority over the Class VI process – but until the Class VI process is clearly triggered, only the State Director has authority to work with the EOR operator.

Therefore, where the rules at 40 C.F.R. § 144.19(b) state that "[t]he Director shall determine when there is an increased risk to USDWs compared to Class II operations and a Class VI permit is required," and describes the factors that must be considered in making the determination, that language can reasonably be interpreted to refer to the State Director's assessment of such factors, up to and until the point where the increased risk to USDWs has been identified. That reflects and properly allows for shared authority over the transition.

[6] U.S. EPA, "UIC Program Primacy: Who Currently Has Primacy" *available at*: http://water.epa.gov/type/groundwater/uic/primacy.cfm (last visited Mar. 3, 2014).

Unfortunately, EPA's draft Guidance describes the Class VI Director as the only entity with authority to demand information from the EOR operator necessary to make the determination whether Class VI permitting is required. Draft Guidance at 16-17. That is not only inconsistent with the Agency's own regulations, it also does not promote the goal of a smooth transition process because it does not adequately recognize that much of the information needed for the transition is already available to the Class II Director. In part that is because the draft Guidance does not reflect an accurate understanding of EOR incidental storage, as described in the next section.

The Re-issued Guidance Must Correctly Describe Incidental CO_2 ***Sequestration in Business as Usual EOR, and Accurately Characterize the Point at Which a Changed Purpose Occurs.***

Under the Safe Drinking Water Act ("SDWA") rules promulgated in 2010, 75 Fed. Reg. 77,230 (Dec. 10, 2010), governing geologic sequestration and the relationship between Class II EOR injection permitting and Class VI permitting of injection for geologic sequestration, an EOR operator with a Class II permit must obtain a Class VI geologic sequestration permit at the point when *both* (1) the *primary purpose* of the ongoing carbon dioxide injection activity changes from the recovery of the oil (or gas) resource, to the long-term storage/sequestration of carbon dioxide, *and* (2) that change *increases the risk of endangerment to USDWs* compared to business as usual Class II operations. 40 C.F.R. § 144.19(a). That two part trigger reflects the language of the SDWA, which states that EPA regulations "may not prescribe requirements that interfere with or impede…any underground injection for the secondary or tertiary recovery of oil or natural gas, *unless* such requirements are essential to assure that underground sources of drinking water will not be endangered by such injection." 42 U.S.C. § 300h(b)(2) (emphasis added).

Changed purpose. 40 C.F.R. § 144.19(a) describes the operators' duty to apply for and obtain a Class VI permit when the primary purpose of injection has shifted to sequestration (and there is an increased risk of endangerment to USDWs relative to Class II operations). It is the operator who must bring the changed purpose to the attention of the Class II Director.

What is needed is to identify the point, or some indicia of the point, at which the operator must inform the Class II Director of a change in primary purpose. In a typical EOR business as usual regime, the producing wells rim the injecting wells in patterns so that migration of the subsurface fluid and the pressure front is moderated by the producing wells. Data describing the injection-production volumetric balance in a field is one possible metric for identifying the point at which primary purpose shifts, and the operator and Class II Director should discuss whether transition will be warranted.

We suggest the operator also could provide the Class II Director with a declaration of intent, describing whether business as usual EOR with incidental sequestration will continue, followed by sequestration after the cessation of oil production activity, or whether the operation will be shut down when oil production ceases. Clearly, the point when oil production ceases in a field, but injection of CO_2 continues marks a changed purpose, as the only purpose of further injection is CO_2 sequestration.

But the assessment of whether a transition is needed, and also the Class VI permitting (which will involve the Class VI Director as well) will take time. We suggest that the point when the production of oil or gas begins to substantially decline at the end of the life of a field and incidental sequestration increases relative to business as usual could be identified by EPA's revised Guidance as a suggested point when the operator should provide the declaration of changed purpose to the Class II Director, as part of its ongoing reporting.

Increased risk relative to Class II. Simply identifying changed primary purpose, however, is not sufficient to trigger the need for Class VI permitting – the Director must then also assess whether there is associated increased risk to USDWs, relative to Class II operations, considering the factors set out in 40 C.F.R. § 144.19(b).

To be clear: there are two possible scenarios that may arise at the point when the primary purpose of Class II injection shifts to long-term sequestration: either (1) risks to USDWs may increase, or (2) risks to USDWs may not increase. Under the second scenario, the EOR operator continues to withdraw the declining petroleum resource but the balance of total injected to produced fluid volumes (and therefore the risk to USDWs) does not change despite a possible increase in the proportion of CO_2 in the injectate (this has been called "storage with incidental production"). While the EOR project (as distinct from the injection well) is retaining more CO_2, and the primary purpose of the injection is shifting, the risk to USDWs has not increased.

Unfortunately, EPA's draft Guidance does not reflect this important point, which is fundamental to a correct understanding of incidental carbon sequestration in EOR. In particular, EPA misstates several technical considerations relevant to the determination of when the risk of endangerment may increase. For example, EPA, in Figure 4 of the draft Guidance, describes what it considers to be a typical operational/ transitional model – but the figure is technically incorrect. EPA seems to have conflated oil production decline with reduction in total fluid withdrawals: Figure 4 shows injection rates (and risk) increasing as production decreases. In fact, as production declines, there will be less oil produced, but the total volume of produced fluids can remain constant.

As noted above, the principal operational change that clearly identifies the potential need for a determination whether transition to the Class VI regime is warranted is the cessation of active control of CO_2 injection by production wells.[7] It is at the point when the operator systematically shuts down the producing wells for the purpose of increased storage, but maintains the injection volumes in a mature CO_2 flood, that the injection to withdrawal ratio ("IWR") increases and the underground plume will no longer be controlled by production. At this point the area of review ("AoR") may need to be reevaluated, and other aspects of Class VI well operations may become necessary. The potential for increased risk relative to Class II operations is indicated.

But EPA's Figure 4 overstates the risk of continuing to operate under Class II permits where oil production is declining and the CO_2 fraction of the injectate is increasing, but injections remain balanced with production. Although at that point, the "primary purpose" may in fact be CO_2 sequestration (with incidental production), there is not "an increased risk to USDWs" – and so transition to Class VI is not yet warranted – nor is it authorized by the statute or the regulations.[8]

While short-term periods of imbalance are needed, particularly at the beginning of EOR operations (e.g. pressuring a field up to minimum miscibility pressure at the start of a CO_2 flood, a normal operating procedure under Class II), evidence of continuing or increasing CO_2 injection but reduced production of all fluids in a mature (oil-producing) field, may signal a change in the area of elevated risk of leakage to USDWs requiring Class VI assessment and monitoring. As an operator begins to shut in production wells, while maintaining injection volumes, the CO_2 plume would be expected to migrate and be accommodated outside the producer wells and move beyond the business as usual injection and production patterns; as a result the AoR may need to be increased and be accompanied by plume and pressure front analysis, risk analysis and an evaluation of the need for corrective action beyond the standard ¼ mile radius and a ultimately a transition to Class VI.[9]

---

[7] At that point the purpose of any continued CO_2 injection clearly has shifted from oil and gas production (because production has ceased) to sequestration.

[8] Additionally, another plausible scenario is one in which the water fraction of the injectate decreases, but the CO_2 fraction increases, but the operator disposes of the produced brine offsite. Balanced and constant reservoir pressure can also be maintained under this scenario, thereby increasing the effectiveness of the CO_2 storage without increasing risk. Under this scenario, the risk relative to Class II operations remains unchanged although the primary purpose has become storage with incidental oil production. The draft Guidance does not take this scenario into account. It is important because it is not technically governed or addressed by Class II requirements (which are for oil and gas production only). EPA must address in its revised Guidance whether Class VI well is required where fluid balance is maintained just as it was during baseline EOR activity for the field.

[9] Again, it is important to recognize that it is not a foregone conclusion that pressures would increase in the receiving formation when producers are shut in (as erroneously indicated in Figure 4), since formation pressure is dependent on porosity and permeability conditions, including the presence of

EPA's Reissued Guidance Should Help Operators and the Class II Director by Characterizing the Point at Which a Transition to Class VI Permit is Required

EPA's reissued Guidance should frame a transition *process* that is consistent with the reality that incidental sequestration does occur with EOR activity, before and during the transition to a system in which CO_2 is being injected, but no more oil is being recovered. EPA should provide straightforward, predictable criteria so that operators will understand that they can remain within their baseline business as usual enhanced oil recovery (Class II) conditions until the cessation of production activity,[10] and that also recognize the existence of the incidental storage that occurs as a result.

Under the current Class II rules, specifically at 40 C.F.R. §§ 146.23(b) & (c), the Class II Director is authorized to request the monitoring and reporting of additional information. That information might include information enabling the characterization of baseline metrics of production and injection. Additionally, the Class II Director, as part of the ongoing monitoring and reporting requirements, could request a declaration by the operator of its intention for future operations: Does the operator intend to remain in business as usual EOR conditions as long as there is incidental oil production, or does the operator intend to shut down all operations and leave the injection site? Or, as a third alternative, does the operator intend to shut down the production wells, but continue to inject CO_2, for sequestration?[11]

Unless the third alternative is planned, there should be no increased risk to USDWs relative to its normal Class II operations, and therefore an evaluation of the need to transition to Class VI permitting is not required. Collection of information about baseline EOR conditions helps the Class II Director ensure that no increased risk is occurring.

Conclusion

In the re-issued Guidance, EPA has an opportunity to provide clarity to EOR operators about how they may continue to conduct EOR with incidental storage under

---

permeability pathways. Therefore, it cannot be concluded *a priori* that injection rates or pressures would increase under a regime with a "primary purpose" of CO_2 storage.

[10] Note that Class II wells are defined as wells which inject fluids for the enhanced recovery of oil or natural gas, among other things. 40 C.F.R. § 144.6 (b). But the cessation of resource recovery is at least an indication that a different kind of well permit is required, whether Class VI (where risk to USDWs is increased relative to Class II).

[11] The regulations list specific monitoring and reporting elements that must "at a minimum" be provided by the operator; this language permits the Class II Director to add to those minimum requirements. See, e.g. 40 C.F.R. § 146.23(b) ("Monitoring requirements shall, at a minimum, include [listed elements (1) through (5)]").

their Class II permits, and a process by which the need to transition to Class VI permitting may be determined. CATF suggests EPA, in re-issuing the Guidance should evaluate whether and how the balance of injections to withdrawals can be a useful as an indicator of changed purpose, and therefore the need to evaluate the potential for increased risk. EPA should structure its Guidance to focus on how operators might practically screen their operations to characterize business as usual baseline conditions, which will allow an operator to remain within Class II if so desired but, at the same time, enabling the assessment of any associated increased risk to USDWs by the Class II Director.

This process should not impose excessive burdens on operators but instead should provide confidence to EOR operators and allow an informed determination on the part of the Class II Director as to whether a Class VI permit may be needed. At the point at which it is clear that the transition is required, the Class VI director should be able to obtain from the Class II Director, some of the information it will require for permitting, under this approach.

Respectfully submitted,

/s/Bruce Hill, Ph.D.

____

Bruce Hill, Ph.D.
Chief Geoscientist
bhill@catf.us

/s/Ann Brewster Weeks

____

Ann Brewster Weeks
Senior Counsel and Legal Director
aweeks@catf.us

Clean Air Task Force
18 Tremont St.
Boston, MA 02108
617-624-0234